ATTACHMENT 10

A Better Approach to Market Power Analysis

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Summary/Introduction

This paper shows that analyses of market power for wholesale electric markets are best done using electricity market simulation models rather than the more commonly used Hirschman Herfendahl Index (HHI). Market simulation models are more useful than HHI in determining price impacts due to the exercise of market power, since the HHI is far too simplistic to capture the dynamic nature of electricity markets or the behavior of market participants.

Electricity Markets and Market Power

Until restructuring in the electric industry began, wholesale electricity markets were primarily based on bilateral contracts and cost-based power pools. Distribution utilities would enter into cost-based, long-term contracts to meet baseload demand when doing so was less expensive than generating their own power. As demand varied on a short-term basis from their forecasts, distribution utilities would also enter into cost-based short-term transactions in order to match actual demand with supply.[1] Power pools arose to normalize these short-term transactions on a variable cost basis.

Restructuring of the electric industry has led several states to transform cost-based bilateral contract markets or power pools into deregulated poolco markets. These states include California, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. Thus far, only Illinois has deregulated its electric industry without creating a formal poolco or power exchange.

Poolcos are similar to power pools in that they operate in the short term, but differ in that the price of power is determined by market forces, not regulation or costs. In areas where poolcos are established, as current bilateral contracts expire and if poolcos prove profitable[2] to generation owners, most power will eventually be purchased through poolcos rather than on contract.

In a poolco market, generation owners send bids to the system administrator for each unit they own. These bids represent the prices at which owners are willing to sell power from specific units for a specified time period, usually the next 24 hours. The system administrator dispatches units in order of lowest to highest bid as needed to meet demand for all participants on a continuous basis. The bid price of the last unit dispatched during any given hour sets the market clearing price for that hour. All units dispatched during that hour receive the same market clearing price regardless of the unit bid price.

[1] If an LSE's demand were higher than expected for a given period, exceeding supply, that LSE could buy extra power through short-term firm contracts. Conversely, if an LSE's demand were lower than expected, that LSE could sell excess power through the short-term market.

[2] Profitability is a function of the market price of electricity, costs, and risk.

A perfectly competitive poolco is one in which generation owners bid their production costs (or short-run marginal costs). Market power refers to the ability of one or more generation owner(s) to manipulate the market to their advantage for a sustained period of time, causing prices and profits to increase.

Exercising Market Power

In a poolco, generating firms have an incentive to increase the market clearing price since it is paid to all units dispatched in each time interval. There are two principal mechanisms by which firms may exercise market power in a poolco. The first mechanism, strategic bidding, involves firms' bidding prices above the production costs of their generating units with the intent of forcing up the market clearing price.[3] The benefit of "bidding up" the market clearing price can outweigh the risk of being undercut by a competitor. In fact, the strategy of "bidding up" the market clearing price is always more profitable, as will be demonstrated below, than bidding marginal costs.[4]

This first mechanism, strategic bidding, is facilitated by the fact that the bids submitted by generating firms apply to the next 24-hour period. Since the demand for electricity fluctuates over any 24-hour period, firms can anticipate these changes in demand in their construction of a strategic bidding schedule for this period. Generating firms can construct strategic bidding schedules such that market clearing prices exceed the short-run marginal costs of generation in almost every hour of the day and still remain safe from being undercut by competition.

Strategic bidding could also prove to be a factor in future bilateral contract markets. As owners find that they can "bid up" the price of electricity in poolcos and spot markets, they will only enter into future bilateral contracts if the expected profitability of those contracts is as high as what they can expect in the spot market. Therefore, strategic bidding in poolcos and spot markets is likely to have a direct impact on bilateral contract prices. If owners in a poolco market are found to have market power, then those owners would almost certainly also have market power in a bilateral contract market.

The second mechanism for exercising market power involves firms' withholding some of their capacity in the bidding process in an effort to cause more expensive units higher up the system-wide supply curve to set the market clearing price than would otherwise be the case. Firms that attempt this strategy must ensure that the foregone revenues from not dispatching some of their infra-marginal capacity are more than offset by the additional revenues paid to their actually dispatched capacity. Newbery (1995) has shown that capacity withholding may be profitable to electric generating firms whose market shares range between 10 percent and 40 percent, while Wolak and Patrick (1997) have shown empirically that this mechanism has been an effective way to exercise market power in the electricity spot market of England and Wales. These results are not surprising; capacity withholding is a classic approach to exercising market power in any market.

Market Power Measurement

HHI

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[3] This paper assumes that there is a separate market for capacity in addition to the energy poolco.

[4] Rudkevich et al. proved under certain conditions that a Nash Equilibrium exists in a poolco such that any firm that deviates from strategic bidding has lower profits than firms that engaged in strategic bidding. "Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," the *Energy Journal*. Vol 19, no. 3.

The analysis of market power in the electric industry traditionally relied on the Hirschman-Herfendahl Index (HHI), a measure of market concentration. Since most wholesale power was sold at cost-based, FERC-approved prices, market power was unlikely to be exercised at all.

The HHI is a static index that cannot capture dynamic market effects such as strategic bidding and capacity withholding. The HHI also does not account for:

- market structure;
- transmission constraints;
- transmission costs;
- the balance of supply and demand; and
- the pattern of ownership over the supply curve.

The HHI simply measures market concentration for a geographic area and/or a product market, which is defined fairly arbitrarily by FERC's Appendix A HHI methodology as the region into which electricity can flow within 5 percent of the market price.[5]

The HHI is calculated by the following formula:

$$HHI = \sum S_i^2$$

where S is the ownership share of each firm in the market, with $\sum S_i = 100\%$.[6]

The assumption underlying the use of the HHI for market power analysis is that market power is directly related to market concentration. Proponents of the HHI would argue that since a monopoly owner can exert unlimited market power, a market that resembles a monopoly lends itself better to the exercise of market power than a more competitive market. Although this is true, the ability to exercise market power in electricity markets depends on much more than market concentration.[7] We have found that there is no clear causal link between the HHI (or changes in the HHI) and changes in market price. In fact, we are unaware of any study that has ever been performed that provides a statistical link between HHI values and market power impacts in the US electric utility industry.

Even if a link between HHI values and market power were demonstrated, the FERC guidelines on how to interpret HHI are arbitrary. According to FERC, a market is "unconcentrated" if its HHI is less than 1,000; "moderately concentrated" if its HHI lies between 1,000 and 1,800; and "highly concentrated" if its HHI is greater than 1,800. For purposes of

[5] In calculating HHI using the Appendix A methodology, a potential contradiction arises in which the market price must be defined *a priori*. Recall that HHI is calculated to serve as a proxy measure of how market power might affect the market price. How can the calculation of a proxy variable for market price impact (i.e., HHI) be directly dependent upon the variable (i.e., market price) that the proxy variable is intended to represent?

[6] If the market share of <u>each</u> firm is expressed in percentage terms, the HHI lies between 0 and 10,000. The maximum value of the HHI occurs when there is one firm only in a given industry, with a (monopolistic) 100 percent market share. The minimum value of the HHI occurs in the limit that the industry comprises a very large number of firms, each with negligible market shares.

[7] Electricity is in many ways a unique product. It has at least four properties that make it markedly different from most other products manufactured and sold in other markets: i) it cannot be stored in large quantities in most electric systems; ii) it cannot be readily substituted for, especially in the short term; iii) it can only be transported along existing transmission lines (new transmission lines require long periods of time and are expensive to erect); and iv) generating units are capital intensive, which increases the financial risk for new market entrants in a competitive market and makes maintaining significant amounts of reserve capacity uneconomical. Because of these properties, it may be easier for generators of electricity to exercise market power than for manufacturers of other products sold in competitive markets.

reference, a market with ten identically-sized firms has an HHI of 1,000, while a market with five identically-sized firms has an HHI of 2,000. No theoretical or empirical evidence supports the use of these guidelines; HHIs of 1,000 and 1,800 are round numbers with no empirical significance.

Proponents of the HHI, including FERC, may argue that the HHI can still be used as a reasonable **screening** tool, that markets with HHI below the 1,800 threshold are only moderately concentrated and, therefore, require no further market power analysis. Unfortunately, as will be shown later in this paper, the HHI seems to have absolutely no predictive power in the electric industry. In some days of the year in a given electricity market, prices can go up by 50 percent or more due to strategic bidding alone and can be easily sustained at 10 percent above competitive market prices. Yet the HHI for such a market can be well below 1,800 for **all** days of the year. Furthermore, no single relationship between HHI values and price impacts seems to hold throughout various regions of the country, indicating that the regional impacts of market power depend, at the least, on the regional supply curve.

Market Power Simulation Models & Price Impacts

The most sensible method of calculating market power impacts in an electricity market is to simulate the operation of that electricity market and, thereby, directly measure the price and revenue impacts of firms' strategic bidding and capacity withholding behavior. At Tellus Institute, we have developed a market power simulation model that calculates strategic bids using the Supply Function Equilibrium (SFE) technique originally developed by Klemperer and Meyer in their theoretical paper appearing in *Econometrica* in 1989, and then adopted by Green and Newbery of Cambridge University as a model of strategic bidding behavior in deregulated electricity markets. The SFE technique was further refined at Tellus by Dr. Aleksandr Rudkevich.[8]

The SFE method interprets the energy market as a simultaneous bidding process in which each profit-maximizing generating firm offers bids for electric energy in the form of a supply curve (or supply function which indicates how much generation the firms are willing to sell at different unit prices), while a system administrator is responsible for ordering the bids and dispatching the units so as to meet the demand for electricity at least cost in each time interval. In the Tellus model, generating firms act in self-interest and do not engage in explicit collusion, either by directly exchanging information or by agreeing to raise prices. The model does assume that each competitor's variable costs of production are known.

The outcome of this bidding process, known as the "Nash Equilibrium," is a combination of the individual bidding strategies of each firm that satisfies the following condition:

> **if, (a) one firm bids a supply curve that deviates from this strategy; and (b) all other firms bid supply curves that adhere to this strategy; then the profit of the one firm departing from this strategy will not increase.**

Generating firms are likely to adopt such Nash Equilibrium-based strategies in their daily bidding for two major reasons:

<u>Reason 1</u>. It is rewarding for a firm to bid according to the Nash Equilibrium strategy when competing firms also bid according to the Nash Equilibrium strategy.

[8] Rudkevich et al., the *Energy Journal*.

Reason 2. The Nash Equilibrium strategy is stable: any firm that deviates from this strategy has a strong incentive to return to it.

The Tellus market power model performs a simple unit dispatch, then calculates prices and revenues based on both marginal cost bids and on calculated strategic bids. Market power is then measured by comparing the difference between the marginal cost or "perfectly competitive" prices and the strategic or actual prices. In particular, the Tellus market power model calculates the Price-Cost Margin Index (PCMI).

$$PCMI = \frac{(AP - PCP)}{PCP} \times 100\%$$

where AP = Actual Price and PCP = "Perfectly Competitive" Price.

Because PCMI has the "perfectly competitive" price in its denominator, it allows comparison across various scenarios that may have different actual prices. Such a PCMI-type ratio can be computed for both the electricity prices and the revenues received by generation owners – the slight difference between these two solutions will be due to price elasticity effects for demand.[9]

With simulation models, market power can be measured directly rather than inferred erroneously from a simple, static, market concentration index like the HHI. FERC, by recently issuing Requests for Comments **(Docket # PL 98-6-000)**, seems to have recognized the importance of simulation models. We hope to demonstrate in the following sections of this paper that direct simulation models perform better than the HHI in predicting the exercise of market power.

Comparison of PCMI and HHI results

The following figures present results obtained using the Tellus Market Power model for both the New England Power Pool (NEPOOL – 25,000 MW), with 29 owners, and a large area of about 48,000 MW with 22 owners centered around Kansas City, which we refer to as the Missouri/Kansas region (MKR). **Figures 1** and **2** present the PCMI for each day of the year sorted chronologically. In this analysis, the yearly average PCMI is about 8 percent for NEPOOL and about 10 percent for MKR, which means that owners in their respective regions can increase revenues (and increase the price of electricity) by these percentages simply by bidding strategically.[10]

[9] The Tellus market power model actually uses **revenues** to calculate "PCMI" rather than **prices**. All PCMIs presented in this paper are based on revenues.

[10] The PCMIs presented in this paper differ from the PCMIs Tellus Institute found for the Missouri/Kansas region as submitted in testimony before the Missouri PUC. Our analysis submitted with that testimony used six modeled day-types rather than 365 days of load. The modeled day-types allowed us to adjust the supply curves to reflect scheduled outages as they would be planned to account for the differences in day-type demand. For the analysis contained in this paper, we developed a single supply curve that does not reflect any scheduled outages in order to easily model 365 different days of load. This new analysis is presented only in order to illustrate certain issues and is not an estimation of what we believe are the full impacts of market power.

Figure 1

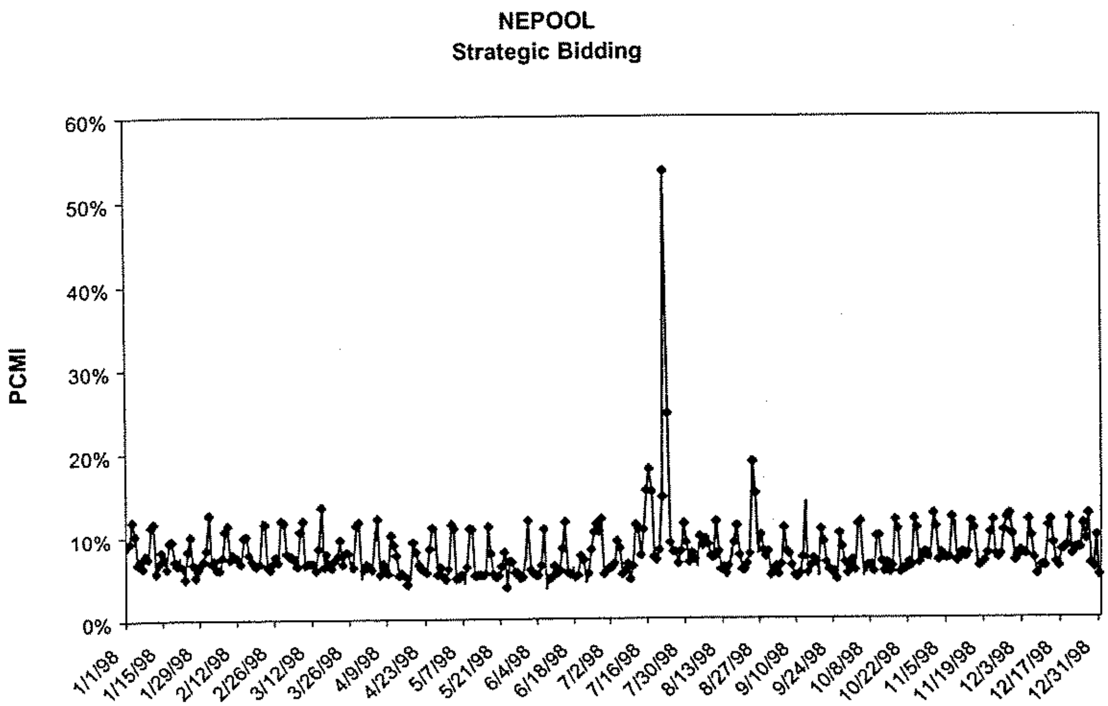
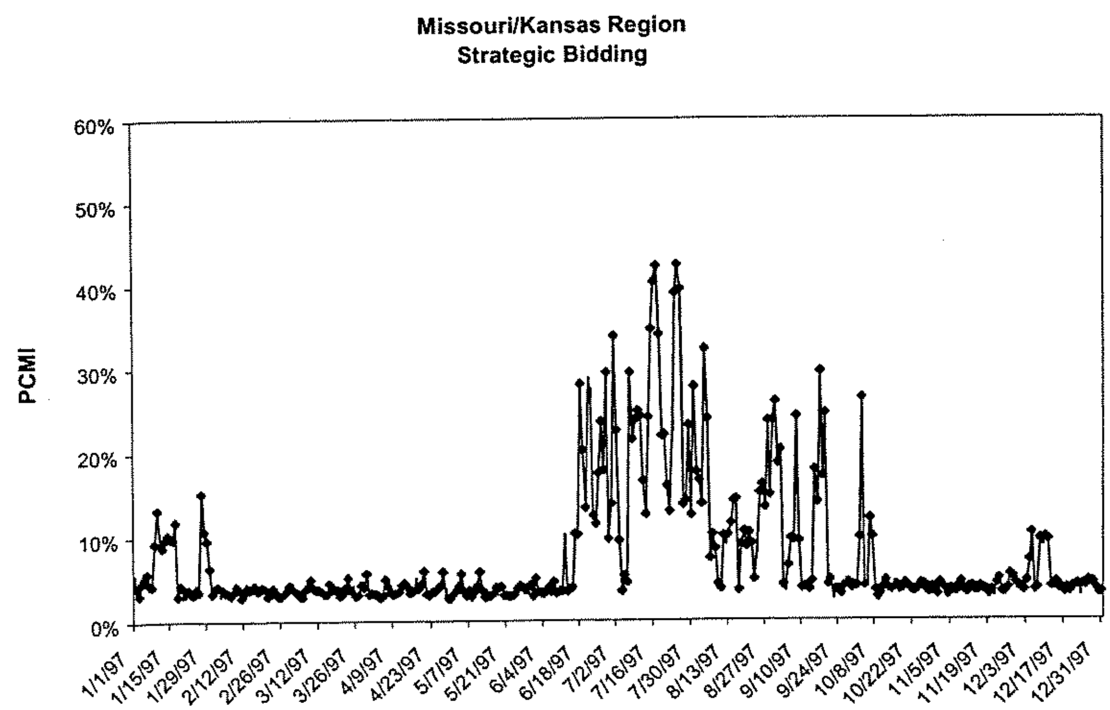


Figure 2

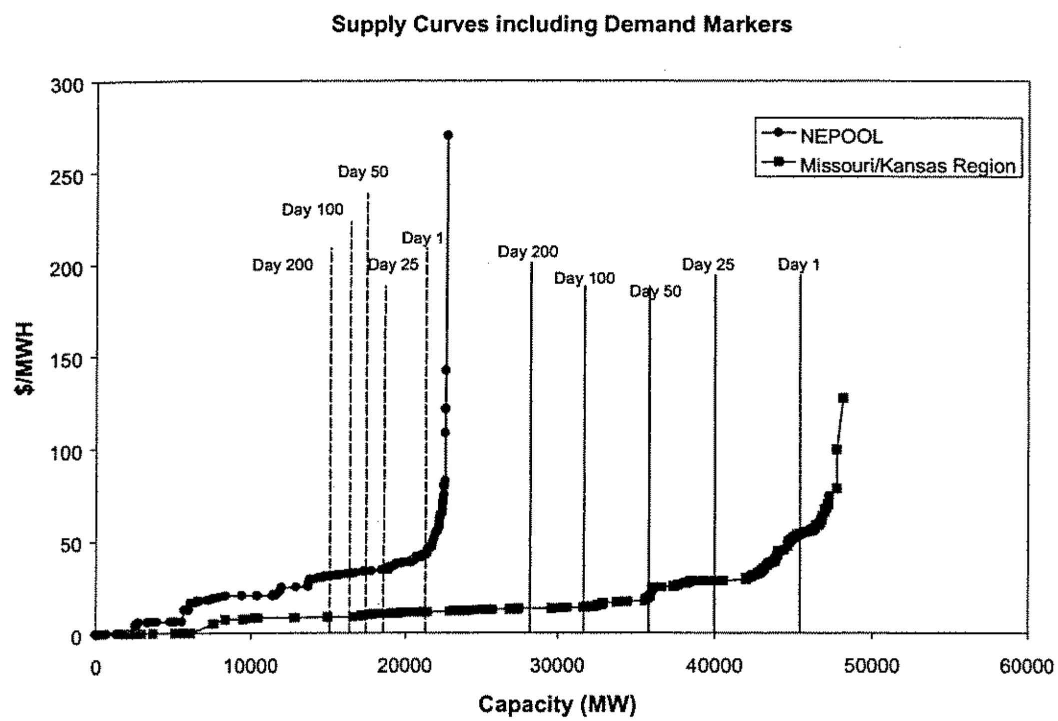


In comparing the two systems, the differences in the PCMI can be explained largely by the interaction of each system's supply and demand curves, as shown in **Figure 3**. **Figure 3** depicts each system's supply curve and selected daily peak loads. Day 1 refers to the day of the year with the highest peak load, while day 200 refers to the day of the year with the 200th highest peak load. Note that the section of the MKR supply curve between Day 1 and Day 25 is much steeper than the corresponding section of the NEPOOL supply curve. MKR's steeper supply curve (for days 1 through 25) explains the greater volatility, relative to NEPOOL, in PCMI during summer, the highest peak demand period. Alternatively, NEPOOL's summer PCMIs are less volatile than MKR's summer PCMIs because the section of the NEPOOL supply curve (for days 1 to 25) is flatter.

Similarly, the area between Day 50 and Day 200 on the MKR supply curve is flatter and lower in absolute cost than the corresponding section on the NEPOOL supply curve. Again, this difference in the shape of supply curves explains for low-peak days how the PCMI for MKR is lower and less volatile than the PCMI for NEPOOL.

We would expect that steeper supply curves result in higher PCMIs because in strategic bidding, owners base their bids on the expected bids of the next most expensive units on the supply curve. If the next most expensive units are only slightly more expensive, then the strategic bid will *not* be much higher than the variable production costs of the unit being bid. However, if the next most expensive unit is much more expensive to operate, then the strategic bid *will* be higher.

Figure 3



The Tellus Market Power model also calculates daily HHI values, which are shown for the two systems in **Figures 4** and **5.** The HHI changes on a daily basis because we measure the concentration of firms actually delivering power into the system in each day; as demand changes, so does ownership concentration and, therefore, HHI. Calculating the HHI for each day is equivalent to calculating it for each product market as FERC advocates as part of its Appendix A analysis for mergers. HHI values vary much less (5-15 percent) from day to day than PCMI values vary (100 – 500 percent). Furthermore, the HHI values for both systems remain well within the range considered as only "moderately concentrated" according to FERC merger guidelines. Yet the average annual PCMI for both systems exceeds the Department of Justice's 5 percent "do no harm" price impact guideline.

Information presented in **Figures 4** through **6** does not represent a merger, but we include the FERC merger guidelines in these figures to illustrate that these systems would pass FERC's HHI merger screen despite the obvious market power threat illuminated by PCMI. To illustrate the actual impacts of a merger, we present in **Figure 7** results of analysis recently submitted in testimony before FERC and the Missouri PUC.

Figure 4

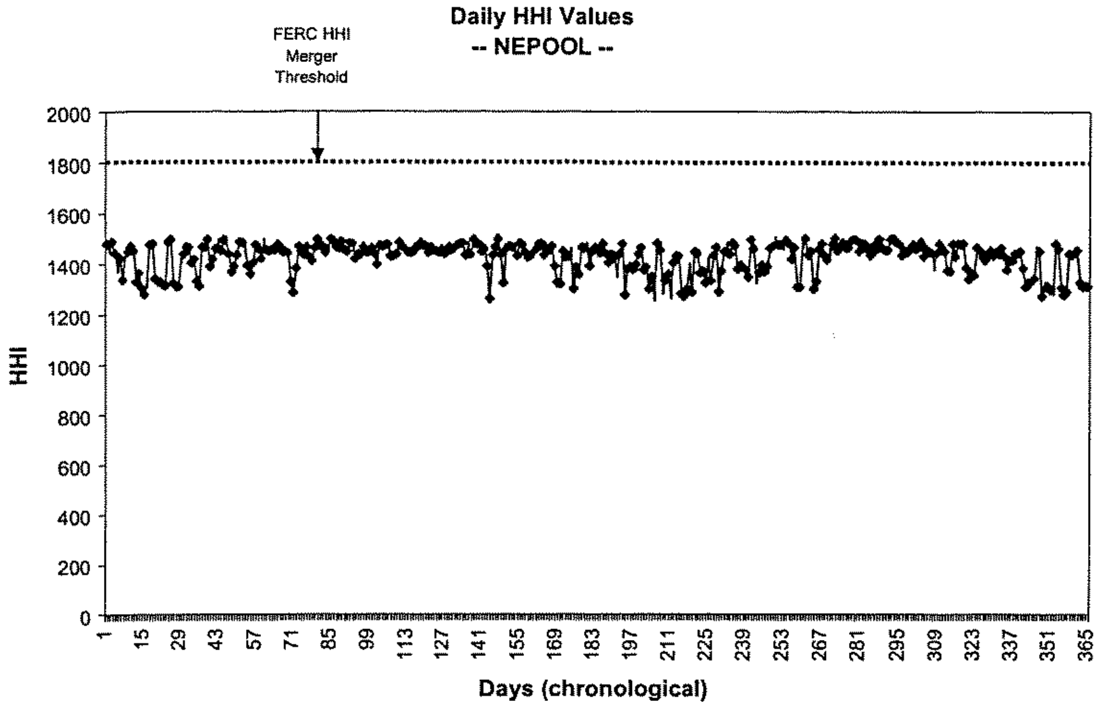


Figure 5

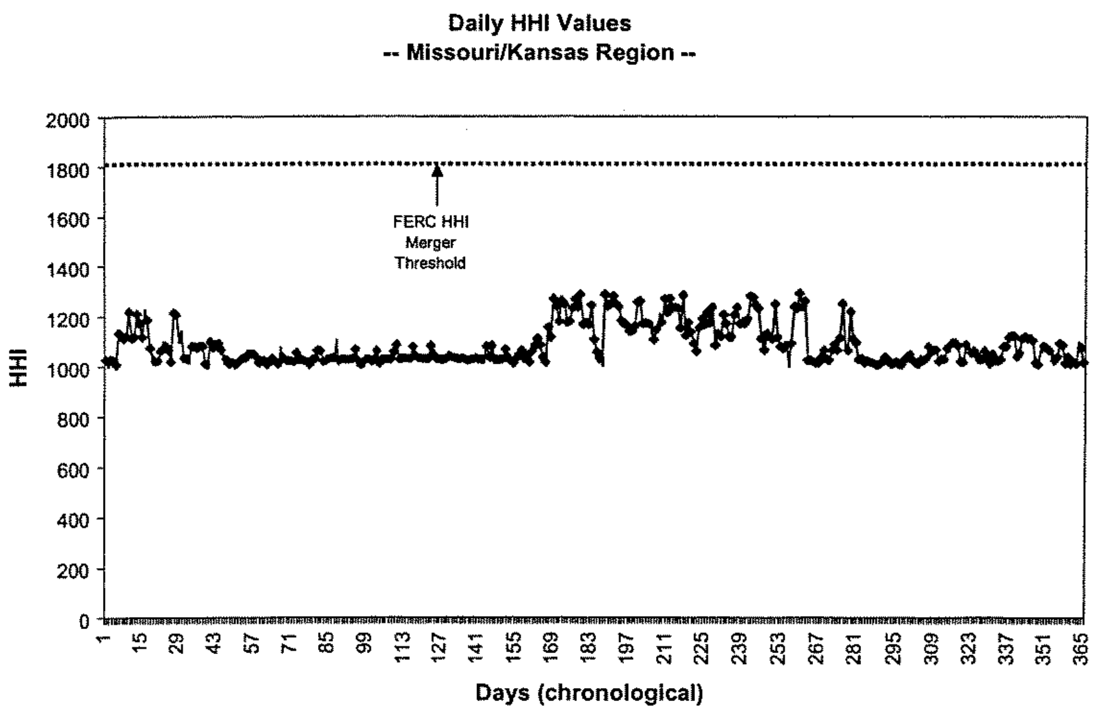
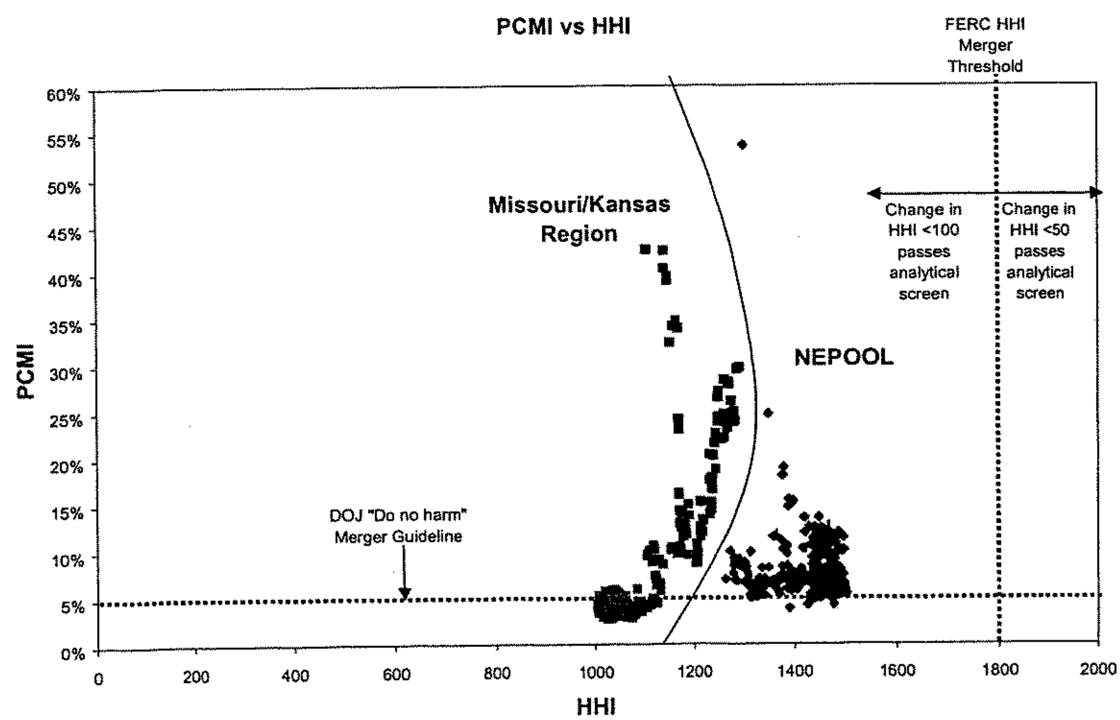


Figure 6 is a scatter plot of PCMI versus HHI for both systems for every day of the year. This graph shows that HHI cannot be used to predict market power. Higher HHIs are clearly not correlated with higher PCMI values, especially for NEPOOL. In both systems, the highest PCMIs occur during days with mid-range HHIs. For each system, HHIs stay well below the FERC threshold of 1,800 for all days of the year. In contrast, the highest NEPOOL PCMI is 54 percent, which is far above the Department of Justice 5 percent guideline. A PCMI of 54 percent means that owners of generation in NEPOOL receive 54 percent more revenue for that day due to strategic bidding than they would receive in a competitive market without strategic bidding. Yet, the HHI for that day, only 1,301, is toward the low end of the range of HHIs for the whole year – 1,262 to 1,502.

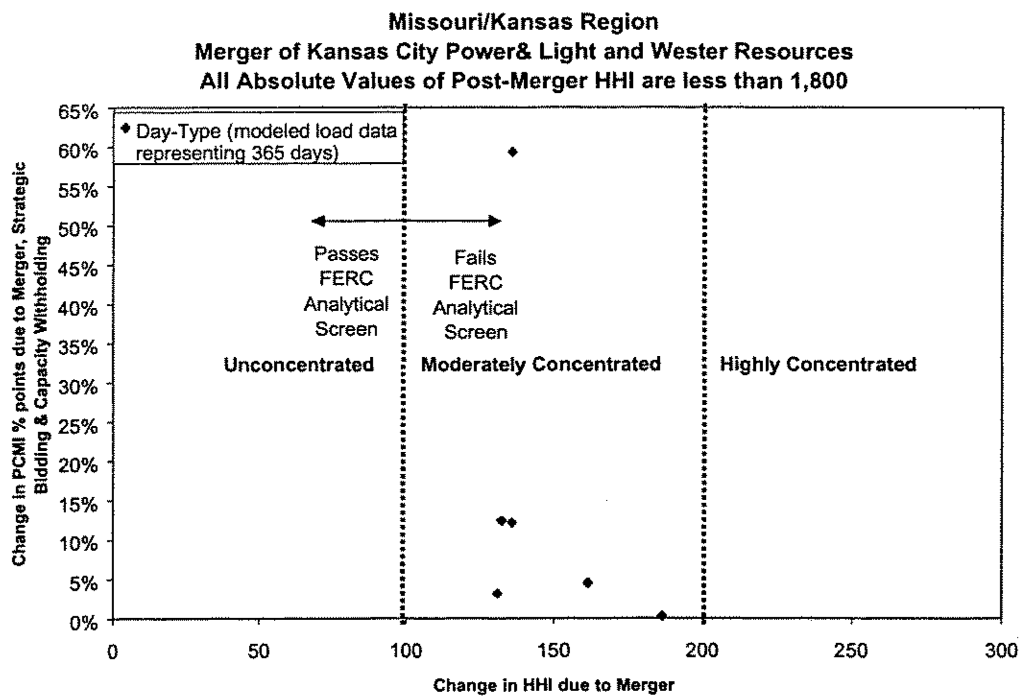
Not only does HHI fail to predict PCMI, the relationship between them is not consistent from one system to another. NEPOOL HHIs are consistently higher than MKR HHIs, yet NEPOOL PCMIs are lower on average than MKR PCMIs. This comparison alone demonstrates that market power is far more complicated than simple measures of market concentration like HHI would lead one to believe; the HHI cannot begin to capture the nuances that a market simulation model can.

Figure 6



In **Figure 7**, we show results from an analysis of the proposed merger between Kansas City Power & Light and Western Resources, which is contained in recent testimony before the Missouri PUC. This analysis is much more detailed in terms of representing supply curve outages than the other analysis presented in this paper. A consequence of greater detail on the supply side is less detail on the demand side in order to make modeling manageable. Thus, **Figure 7** contains only six data points rather than 365 because we modeled demand as six day-types.[11] We present in **Figure 7** the change in HHI and the change in PCMI percentage points as a result of the merger. All absolute HHI values are below 1,800, and all changes in HHI are between 100 and 200. Although the merger would technically fail FERC's Appendix A HHI screen, most mergers that are moderately concentrated are approved by FERC. However, the changes in PCMI clearly indicate serious market power problems.

Figure 7



Factors that Influence Market Power

This section examines some of the factors that influence market power through various scenarios based on the MKR data. The PCMIs in the following graphs are all in order of the peak hour in each day, such that day 1's peak hour is the highest of the year and day 365's peak hour is the lowest of the year.

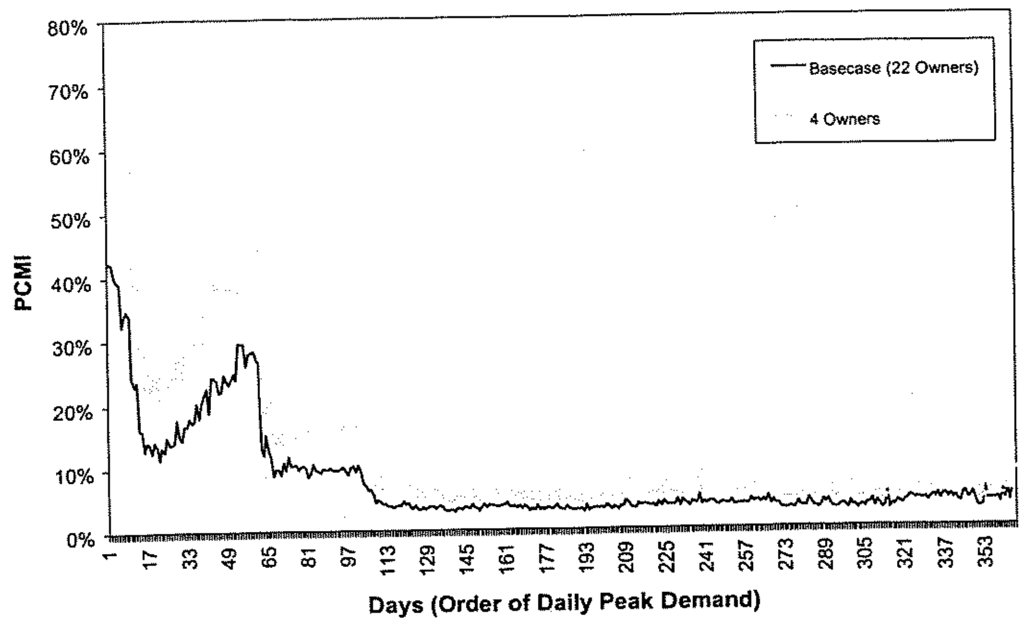
Figure 8 represents three scenarios based on different ownership concentrations. The basecase consists of the original supply curve with 22 owners. In the "4 owner" case, we assigned all units to four owners evenly distributed along the supply curve by ordering the units from lowest to highest marginal cost and assigning the first four units to the four owners, the next four units to the four owners, and so on. As one would expect, the PCMI increases dramatically

[11] We found that actual and modeled load (day-types) result in variations of average yearly PCMI of only about a percentage point, so day-types accurately reflect annual conditions.

as ownership becomes more concentrated. What is less intuitive is that ownership concentration directly shifts up the PCMI each day of the year, which is not how PCMI changes as a result of changes in peak load uncertainty and supply-demand balances, as described below. Also as expected, the greatest impact of ownership concentration on market power occurs in the days with the highest daily peaks.

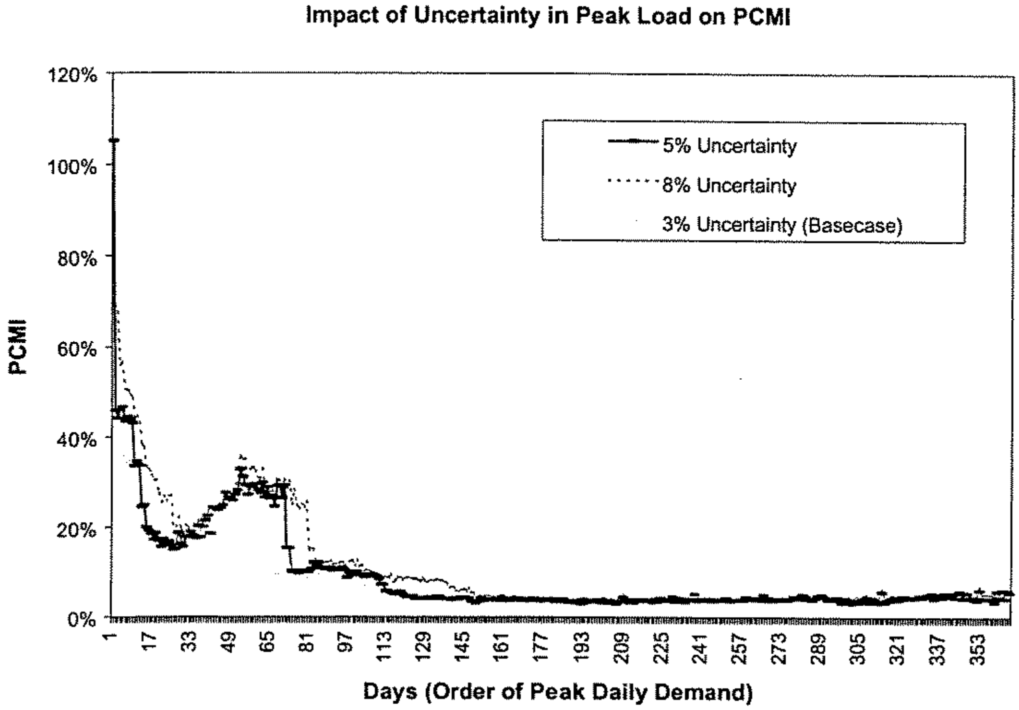
Figure 8

Ownership Comparisons



Another factor that directly influences potential market power is the uncertainty in peak load forecasts. Because owners submit bids for the next 24-hour period, they must forecast peak demand in order to determine what their strategic bids will be. Forecasted and actual demand almost always differ by several percent due to short term changes in weather and other factors. To simulate the level of uncertainty in demand forecasting, the Tellus Market Power model requires the user input a percentage uncertainty in peak load. As **Figure 9** shows, the greater the uncertainty, the higher the PCMI.

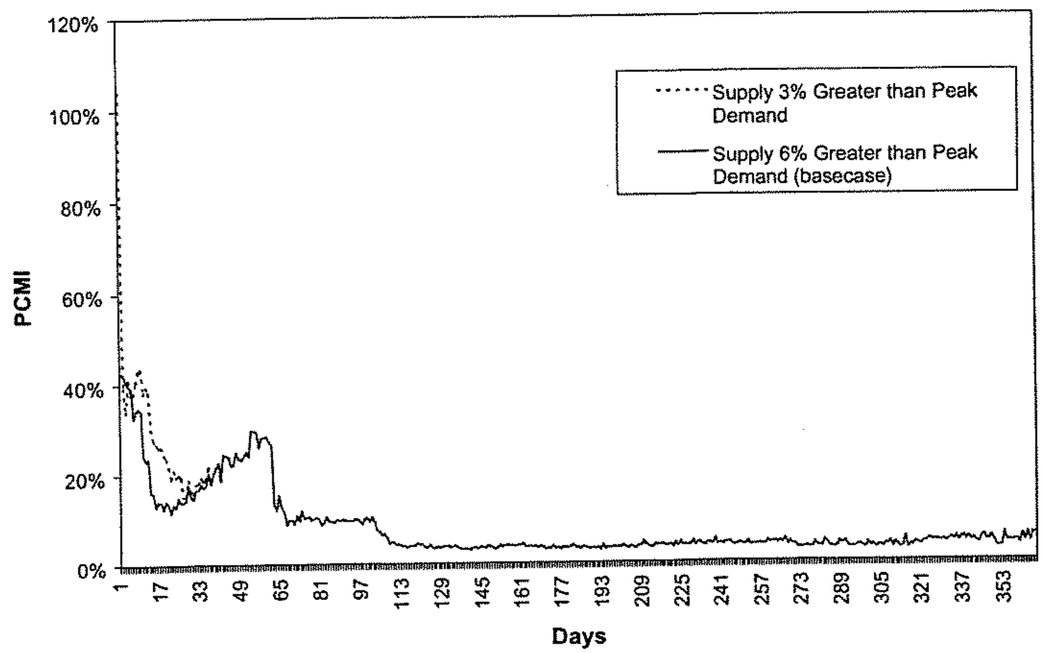
Figure 9



In addition, how closely total supply and peak demand match also affects market power considerably in the highest peak days of the year, as shown in **Figure 10**. This effect becomes negligible for lower peak demand days. For the "3 percent above peak demand" scenario, we removed about 1,200 MW of capacity from new combustion turbines located on the supply curve at around $30 per MWH. As expected, the impact on market power is such that more capacity leads to lower prices. This effect is only noticeable in high peak demand days when demand is at a level requiring electricity costing around $30 per MWH or higher.

Figure 10

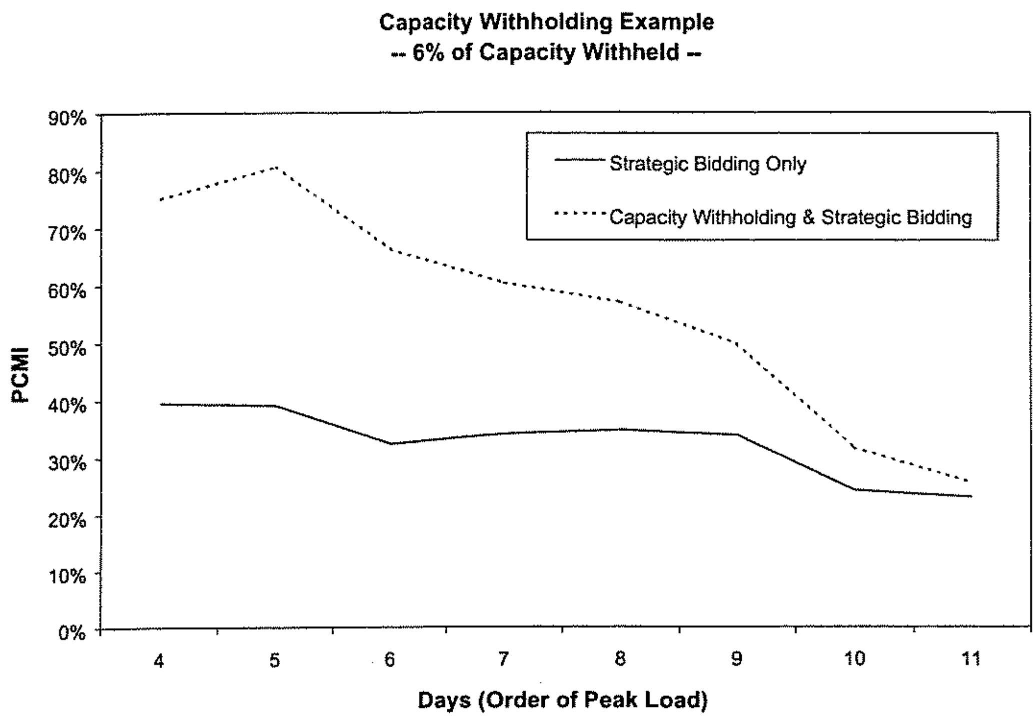
The Impact of Supply-Demand Balance



Capacity Witholding

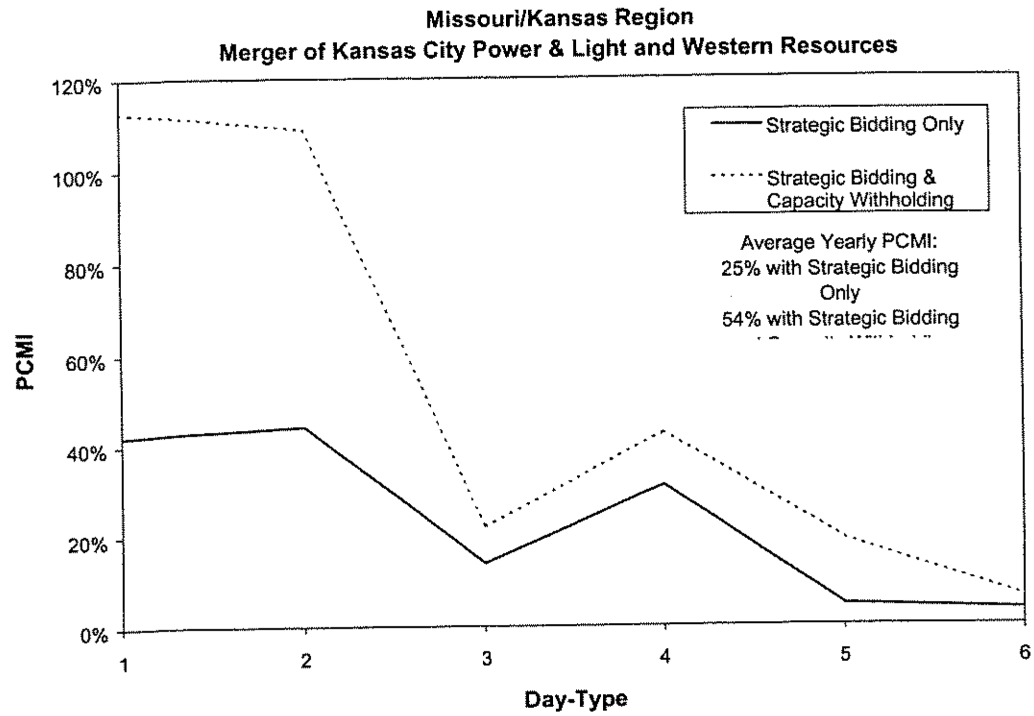
Another important factor influencing market power is the distribution of ownership over the supply curve. Ownership patterns greatly impact capacity withholding. An owner withholds capacity in the hope of raising the market clearing price only if he/she has enough other capacity that will receive the higher price to compensate for the foregone revenues of the capacity withheld. Thus, if an owner's capacity is not at least partially distributed along the supply curve, he/she will be much less likely to profitably withhold units. Although **Figure 11** does not represent capacity withholding in terms of ownership patterns, it does convey the potential windfall available to owners if they withhold. In this example, the set of units withheld was not optimal, but withholding only 6 percent of total capacity more than doubled the PCMI for several days. Therefore, owners have enormous incentive to withhold capacity and to maintain ownership patterns that allow them to profitably withhold capacity.

Figure 11



Our approach to capacity withholding in this example is akin to a "shotgun" approach in finding a set of units to withhold; the same units were withheld for each of the days presented. In reality, owners would withhold different sets of capacity each day based on changes in load. In recent testimony before the Missouri PUC and FERC, Tellus found that on average over the whole year, the PCMI went from 25 percent when firms engaged only in strategic bidding to 54 percent when they also engaged in capacity withholding (see **Figure 12**). Surprisingly, owners could achieve these enormous gains by withholding an average of only 3 percent of capacity throughout the year.

Figure 12



Conclusion

Simulation models afford greater understanding of market power since they take into account the dynamic behavior of market participants, the impact of market structure, and the shape of supply and demand curves. HHI falls short in explaining the nuances of market power due to its theoretically simplistic and empirically unsupportable proxy measures of a complex, non-linear phenomenon. Another advantage of market simulation models is that they can be used to measure the market power impacts of different supply and demand policies, including Renewable Portfolio Standards and energy efficiency programs.